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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	Rulemaking 13-09-011 (Filed September 19, 2013)

PACIFIC GAS AND ELECTRIC COMPANY'S (U-39M) RESPONSES TO QUESTIONS IN ADMINISTRATIVE LAW JUDGE HYMES' MAY 20, 2016 RULING

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Pursuant to the instructions contained in Administrative Law Judge Hymes' May 20, 2016 Ruling (Ruling) in this docket, Pacific Gas and Electric Company (PG&E) submits its responses to the "Additional Questions In Regard To 2018 And Beyond Demand Response Programs." PG&E appreciates the opportunity to respond to the ALJ's questions and contribute to building the record upon which Commission guidance will be provided for the Demand Response (DR) application currently due November 2016.

As an initial matter, PG&E respectfully requests that the Commission indicate as soon as possible whether it plans to postpone the investor-owned utilities' (IOU) 2018 DR applications from the currently-scheduled November 30, 2016 filing date. Having this information as far in advance as possible would help PG&E's application planning to ensure that the appropriate resources are available.[1/]

I. SUMMARY

Beginning in 2018, PG&E believes that its efforts in supporting demand response (DR) will shift from being largely focused on completing the market integration of a leaner portfolio

1/ Guidance for the 2018 application would be needed no later than July 30, 2016 for the 2018 application to be filed by November 30, 3016. If guidance is issued after July 30, 2016, PG&E would need additional time at least commensurate with the delay, plus adding several additional weeks to account for the end-of-year holidays.

of DR programs to enabling the significant growth of cost-effective DR that serves the evolving needs of the electric grid. To achieve what PG&E sees as the necessary evolution of the DR market, PG&E's responses to the ALJ Ruling questions are rooted in four foundational principles summarized hereafter.

A. DR Programs Will Provide A Cost-Effective Platform[2/] To Effectively And Efficiently Convey And Meet Evolving Grid Needs

With the integration of greater amounts of renewable generation into the grid, locations, seasons and hours when DR is most valuable to contribute to balancing supply and demand are evolving: system and local capacity peaks will occur at new times, with situations of steep ramping-up or down, and over-generation expected to arise more frequently. Evolving transmission and distribution grid needs, associated with increasing reliance on distributed energy resources, should also eventually be conveyed by future DR programs.

It will therefore be essential for DR programs to be the platform that flexibly relates fast evolving grid needs, while providing fair and equitable compensation to DR participants, commensurate to the value their contribution provides to the grid.

B. The Utilities Will Be Essential To Supporting The Development Of A Vibrant And Innovative DR Market

With the emergence of a robust and diverse DR market still nascent, PG&E believes that the IOUs have a vital role to play to support DR market transformation by actively enabling all available DR procurement channels:

- PG&E fully supports the Commission's attempt to increase the role of third-party providers through the use of DR direct participation with Electric Rule 24 for DRAM and non-DRAM participants.

2/ "Platform" is defined here as the framework of reference for DR Programs that characterizes the service level agreements between the customers, aggregators, and DR providers to the buyer (i.e., IOU) for the provision of grid services. The platform will describe grid services, their associated value (in form of incentives), and rules of engagement needed in order to participate.

- Complementary to the non-IOU DR programs that will materialize from both Rule 24 DRAM and non-DRAM procurement channels, IOU-operated DR programs will be an additional venue for market participants to access and participate in CAISO markets, as well as a vehicle to expand access to DR programs to new or under-served segments of the market.

The combination of all these procurement channels will result in a more favorable environment for a wide range of third parties and aggregators to enter the DR market, with multiple choices for customers to participate in DR.

C. Providing Flexibility In How Customers Can Participate In DR Will Unlock More Opportunities For Cost-Effective DR To Serve Grid Needs

PG&E is considering a design option for PG&E-operated DR that would offer customers and aggregators the ability to elect their availability to provide value to the grid, in a manner that reflects customers' varied opportunity costs. Such a program option will help mitigate fatigue for more use-limited customers and enable customers capable of more frequent dispatch to receive greater compensation.

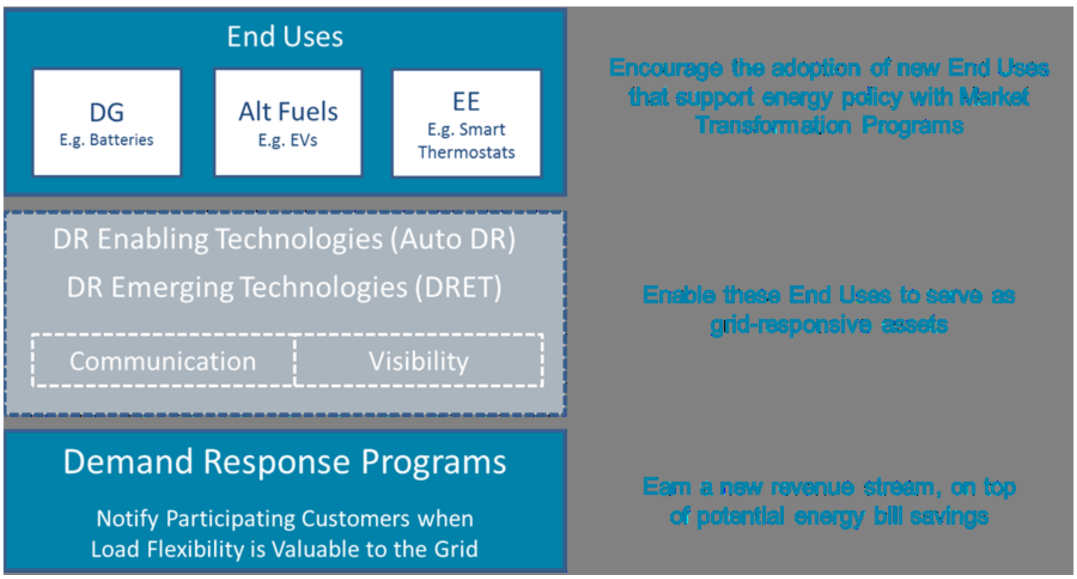
Beyond this program option where the decision to be dispatched is at customers' discretion, the Commission should continue to allow IOU-operated DR programs to have multiple triggers with the discretion in how IOUs apply them. Flexibility in the way these programs are operated and dispatched is important to the ability of IOU-operated DR programs to deliver on the multi-faceted objective to properly support all grid needs.

D. Rather Than Being Tied To Specific End-Uses, DR Programs Should Focus On Becoming The Enablement Platform That Transforms End-Use Loads Into Grid-Responsive Loads

The role of DR programs and DR enabling technologies[3/] is to provide the platform that will support customers in transforming end-use loads into grid-responsive loads to serve the

3/ PG&E is using the following definitions that were provided by the Lawrence Berkeley National Laboratory during the first Technical Advisory Group meeting for the DR Potential Study ordered in D.14-12-024:

evolving needs of the grid. Unlike other PG&E customer programs (Energy Efficiency (EE), Distributed Generation (DG), Energy Storage (ES) or Electric Vehicles (EV)) which support customer adoption of specific end-use technologies, the role of DR programs is not to support the adoption of any specific end-use technology but rather to leverage the end-use technologies that have been adopted to provide specific grid services and to allow customers who have deployed these technologies to be appropriately compensated for providing those grid services, as illustrated.



II. PG&E'S RESPONSES TO THE QUESTIONS IN THE MAY 20, 2016 RULING

A. <u>Category 1 Questions: Demand Response Goal and Objectives</u>

1. *In general, what should the Commission expect demand response to accomplish?*

The Commission should expect that DR programs will create value for utility customers by providing an accessible and cost-effective platform that can accomplish the following:

- "End-use: an appliance, centralized building service, process load, or other electricity consuming piece of equipment (e.g., HVAC, electric vehicles, water pumping, etc.)"; and
- "Enabling Technology: a set of communications, networking, telemetry, control & other systems that enable a DR end-use to provide grid service."

i. Effectively and efficiently convey and meet evolving grid needs:
    1. System and local (transmission and distribution) capacity needs.
    2. System and local needs arising from the integration of greater amounts of distributed and wholesale renewable energy resources such as ramp-up/ramp-down and over-generation.

ii. Engage and satisfy customers:
    1. Provide fair and equitable access for all utility customers, both bundled and unbundled, to participate in DR programs.
    2. Ensure that customers who have responded to an identified grid need are compensated in a fair and equitable manner.

iii. Support the development of a vibrant and innovative DR market:
    1. Support the entry of new and innovative DR providers.
    2. Cost-effectively expand access to DR programs to new or under-served customer groups.

2. In *general, what are your expectations of demand response in California?*

PG&E's expectations for demand response in 2018 and beyond are aligned with the key goals described in response to Question 1. It is PG&E's expectation that DR can continue to be a valuable part of the overall resource portfolio at both the system and local level. In order to meet this expectation, the DR portfolio will need to continually evolve to meet the changing needs of the grid. This will require a more nimble mechanism for program evolution than is possible with the existing DR application process.

3. *Should the Commission set a different goal for load modifying and supply resource demand response? If yes, respond to the first two questions separately for load modifying and supply demand response.*

PG&E does not believe the Commission should set separate goals for Load Modifying Resource (LMR) and Supply Resource (SR) DR at this time. As noted in the DR Potential Study Phase 1 Report (Interim Report issued April 1, 2016), there are potentially significant interaction effects between LMR and SR DR. For that reason, as stated in the Interim Report, page 9: "This highlights the need for careful consideration of the interplay between these resources when creating market and policy plans, since only counting supply DR in isolation without reference to the scale of the complementary load-modifying resource could lead to misaligned incentives."[4/] The fundamental and common goals for both types of DR should be:

- To develop an effective and efficient platform that can support customers in transforming end-use loads into grid-responsive loads, and
- To continually evolve in response to ever changing grid needs and to provide value to IOUs, customers enrolled in the DR programs, and all other customers.

4. *Should the Commission set a different goal for third-party supply resources (e.g., demand response auction mechanism) and utility supply resources (e.g., Southern California Edison's Capacity Bidding Program) bid into the CAISO market? If yes, respond to the first two questions separately.*

No, the Commission should not set different goals for third party vs. IOU-operated resources. Consistent with PG&E's response to Question 3, setting separate goals may result in misaligned incentives thereby reducing value for customers. Furthermore, separate goals could risk foregoing DR participation by customers who prefer a third-party provider over an IOU or vice-versa. Regardless of the type of DR or the channel through which the DR is sourced, the overall goal should be, as expressed earlier, to provide a platform whereby customers can effectively and efficiently transform end-use loads into grid responsive loads, and receive fair compensation for their actions that provide value for both participating and non-participating customers.

4/ At page 9, the Interim Report states:

> …load-modifying and supply DR should be viewed as two parts of the DR resource base. Shifts in the underlying baseline load (load-modifying DR) can reduce system needs for capacity, but also incrementally reduce the ability of effected loads to participate in wholesale electricity markets as dispatchable DR (i.e., the load impacts from load-modifying DR can reduce the quantity of supply DR available).

And

> This highlights the need for careful consideration of the interplay between these resources when creating market and policy plans, since only counting supply DR in isolation without reference to the scale of the complementary load-modifying resource could lead to misaligned incentives and under-counting of the full DR contribution.

5. ***What metrics and targets (e.g. x number of customers per year per program or y percent of customers able to respond within z number of minutes) should the Commission use to measure the following aspects of demand response: Customer participation, engaging new customers, reliable customer response, deployment of automated technologies, market transformation; and integration with other distributed energy resources including battery storage.***

While all the metrics enumerated in Question 5 are generally worth tracking and potentially could represent good targets, PG&E maintains that the single most important goal for DR programs is value creation. The Commission should avoid setting targets or choosing metrics which are not directly tied to the goal of value creation. A DR program portfolio that has many enrolled customers, MW or other attributes as enumerated in Question 5 but does not provide needed grid services or provides grid service that are not cost-competitive, does not create value. Targets and metrics should be chosen based on their ability to measure whether DR is providing needed grid services and/or greenhouse gas (GHG) reductions in a cost-effective manner compared to competing resources. As grid needs, the DR market, DR programs, DR providers and DR participants continue to evolve over time, targets and metrics will also need to evolve to remain relevant and useful.

6. ***Are there additional demand response aspects for which the Commission should develop metrics and targets?***

As mentioned in response to Question 5, the DR aspect that is missing from the list enumerated is value creation.

7. ***Explain and justify why and how the Commission should prioritize the demand response aspects provided in questions five and six above?***

The first priority should be to focus on ensuring that the DR Cost-Effectiveness Protocols accurately capture the full range of value that DR program portfolios are creating. For example, the DR Cost Effectiveness Protocols do not assign value to load-increasing DR that can mitigate over-supply situations. The second priority should be to complete the DR Potential Study and to leverage it to develop a DR Strategic Plan. This plan could then be used to drive the metrics and targets that reflect the evolution of DR programs. The Commission should also prioritize ongoing updates of the DR potential study, DR avoided costs and the DR cost-effectiveness framework, as well as load research and other customer research that can support value creation through the use of DR.

8. ***Who should be responsible for meeting the goal and objectives of demand response?***

The Commission and CAISO should be responsible for ensuring that both regulatory and energy (operational) market frameworks provide opportunities and support value creation through DR. The IOUs should be responsible for effectively and efficiently communicating grid needs to DR Providers and for providing an easily accessible platform that enables customer end-use loads to be transformed into grid-responsive resources. DR providers should be responsible for ensuring that a) DR programs create value for both participating and non-participating customers, b) customers are treated in a fair and equitable manner and c) customers have high satisfaction with their DR program experience.

B. Category 2 Questions: Improving Demand Response Program Design

1. ***The Interim Report found that demand response resource potential and costs within an end-use category varies widely across customer sites depending upon cost of incentives, program administration, marketing and individual customer load shapes. The report recommends targeting customers within each sector who have eligible end-uses with strong coincidence between end-use load baselines and times of system need, large potential load reduction, and characteristics that indicate a propensity to participate. How should programs be designed to best make use of this information?***

PG&E believes that DR program should not be designed for specific end-use (like direct load control DR programs). DR program design should instead focus on being a platform for transforming end-use loads into grid-responsive loads by:

- operationalizing the notification to participating parties of when increasing or decreasing load, i.e. flexing load, is valuable to the grid as a whole, or locally, and
- providing incentive payment commensurate to the value of the DR resource to the grid that compensates customers' opportunity cost in participating in DR.

This distinguishes the role of PG&E DR programs compared to other PG&E clean energy services and programs such as EE, EV, and DG which focus on incenting the adoption of specific end-use technologies to support California's energy policies.

PG&E agrees that customers' end-use information, within the limits of customer privacy protections for data sharing, is useful for the purpose of marketing and enrollment in DR programs so third parties can efficiently target customers who have eligible end-uses with strong coincidence between end-use load baselines and times of grid need, large potential load reduction, and characteristics that indicate a propensity to participate. However, PG&E does not have readily available information about disaggregated end-uses behind the customer meter:

- In 2014, one of PG&E's DR Emerging Technology (DRET) assessments analyzed and identified existing customer end-use loads on PG&E's system, but its usefulness was limited by the quality of outdated input data. We encourage Energy Division to perform additional research, such as updating the 2009 Residential Appliance Saturation Survey, so that all parties can leverage the customers' end use data for targeted marketing and enrollment in DR programs.
- PG&E has also provided anonymized data to State agencies such as city and state governments, and university and nonprofit research organizations so that they can use the data for different purposes, including demand-side program design. These agencies analyze the data, which generally include but are not limited to billing information, monthly usage, seasonal usage, and rate schedule, and publish reports based on the findings. Third party vendors and manufacturers utilize these reports to perform targeted marketing and develop business plans customized to the California market.

2. ***The* Interim *Report recommends integrating demand response with other clean energy services to reduce costs, increase potential and decrease customer confusion. The report points to a growing number of integrated measures that provide both energy efficiency and demand response capabilities. These integrated measures include programmable communicating thermostats and other technology, which provide energy management, convenience, and may reduce the cost of enabling demand response. What policies or benchmarks should the Commission adopt to support such integration? Explain and justify whether and how the Commission should ensure that new construction includes modern demand response enabling technologies?***

PG&E agrees that integrating DR with other clean energy services such as EE, DG, and EV could improve customer experience by minimizing confusion, increasing demand-side management (DSM) potential and potentially reducing overall costs. There are multiple instances in which PG&E already provides integrated EE/DR offerings to our customers, but likely not to the degree envisioned in the Interim Report. Current integrated offerings include but are not limited to:

- Integrated energy audits to large commercial and industrial (C&I) customers to help them identify EE and DR opportunities in their facilities.
- Combined Automated Demand Response (ADR) Program and EE Customized Retrofit Rebate Program to offer integrated offerings to large commercial and industrial (C&I) customers whenever possible.
- Leverage EE Residential Quality Maintenance Program to offer SmartAC to residential customers.
- Leverage Assembly Bill (AB) 793, a bill that requires IOUs to develop incentive programs for energy management technologies for residential, small-and-medium business (SMB) and low-income customers. PG&E will provide more information on AB 793 offerings in the Tier 2 Advice letter required by the June 10, 2016 Joint ALJ's Guidance on Compliance with AB 793 Activities.

PG&E would propose an integrated DSM approach based on its answer to Question 1 above, where:

- DR programs provide the platform that will support customers in transforming end-use loads into grid-responsive loads to serve the evolving needs of the grid, with incentives commensurate with the value to the grid, for the load shifting or reduction commitment and performance (i.e., energy and capacity payments), but not toward the adoption of an end-use technology.
- DR Enabling Technology incentives should encourage the adoption of a set of communications, networking, telemetry, control & other systems that enable an end use to provide grid services. Typically, an end use technology with DR enabling technology could then be capable of receiving and responding to an ADR signal from PG&E or other third parties.
- It is then PG&E's other clean energy services and programs' (EE, DG, EV, etc.) roles to incent and prompt the adoption of specific end-use technologies, in coordination with third parties.

Requiring new construction to include modern DR enabling technologies (such as advanced lighting and HVAC control) should make it easier for new tenants to participate in a DR program. Title 24 can be a good channel to increase adoption of DR enabling technologies in new construction, but there are obstacles still to be overcome. PG&E addresses Title 24 in greater detail in its response to Question 3 below.

3. ***The Interim Report observes widespread confusion among building code officials and market actors regarding the intention of Title 24 requirements for automated technology. The Interim Report recommends that the Commission evaluate knowledge gaps and develop training sessions to address the gaps. Should the Commission evaluate knowledge gaps for Title 24 requirements? How should such an evaluation be performed? What policies should the Commission adopt to ensure that Title 24 can lower the cost of demand response automation?***

PG&E agrees with the Interim Report's finding that there is confusion among building code officials and market actors regarding Title 24 requirements for DR automated technology. A 2014 survey indicated that ~70% of California building officials had little or no familiarity with the DR related code.[5/] An LBNL workshop, hosted in November 2014, provided similar indications of gaps in market awareness.[6/]

To start addressing this confusion, PG&E launched a DRET assessment in 2015 on how to effectively inform key market actors throughout the Title 24 industry. The assessment leverages existing IOUs' Statewide Codes and Standards team's compliance improvement training and outreach, and expands the DR-specific materials available. A report, expected to be available by December 2016, will document various outreach methods conducted and their effectiveness. It will also provide recommendations for stakeholders – both utilities and the broader compliance industry – for mitigating implementation challenges in current and future code cycles. This may include changes to code language as well as specific outreach methods.

While this DRET assessment is anticipated to offer statewide relevancy and an important step for guiding future outreach, its findings will be based on qualitative evidence.

5/ "California Building Officials Title 24 Demand Response Survey Summary for Code Enforcement Personnel in August 2014"

6/ This workshop was held on November 6, 2014 and reviewed the Automated Demand Response building code language that was integrated into the California 2013 Building Energy Efficiency Standards (2013 Title 24).

Therefore, PG&E recommends that the Commission work with all stakeholders to further evaluate knowledge gaps for the Title 24 requirement, while leveraging the findings of the PG&E DRET assessment along with a broader needs assessment performed by the Statewide Compliance Improvement Subprogram within the EE Code and Standard Program.

In addition to the knowledge gap among Title 24 stakeholders, the lack of code enforcement infrastructure is another barrier for new construction adopting ADR enabling technology.

Energy Division could also work with the Title 24 stakeholders to consider the following enhancements to the existing DR code requirements in order to address the knowledge gaps and lack of code enforcement issues:

- Revise Title 24 regulation language to clarify terminology and requirements.
- Improve existing acceptance test language and procedures in the compliance manual.
- Fund education and most effective marketing outreach efforts to increase awareness on code and compliance process.
- Identify challenges on code enforcement by city building department and develop solutions accordingly.
- Work with Acceptance Test Training and Certification Providers (ATTCP) to begin tracking and reporting DR-related compliance documentation.

4. *The Interim Report concludes that providing feedback to customers immediately following a demand response event encourages customers to participate in demand response. How can the Commission design programs to cost-effectively provide feedback to customers?*

PG&E currently provides feedback directly, or access to feedback mechanisms, in a variety of ways before and after DR events to customers enrolled in its non-aggregator programs other than SmartAC. PG&E also has data sharing mechanisms with third parties, which in turn enable them to provide the same information to their customers.

- PG&E provides all large C&I DR customers web presentment through Interact which offers feedback to those customers the day after DR events.
- Non-residential customers participating in Peak Day Pricing (PDP) can elect to receive feedback the day after the event.

- PG&E also provides access to Share My Data (Green Button Connect) to third parties, which enables them to leverage their customers' energy usage information to create post-event reports.
- PG&E performs customer surveys annually on DR programs to collect C&I customer feedback and suggestions. The survey results confirm that providing feedback to C&I customers immediately following a DR event encourages these customers to participate in DR.

For SMB and residential customers, PG&E believes that there is an opportunity for further research to understand how to best encourage DR participation beyond direct immediate feedback mechanisms. For example, feedback from some mass-market aggregators indicates that they are successfully using a "set-and-forget" approach to DR participation through leveraging end-use technologies and automation that do not impact customers' lifestyle, comfort or business operations. This indicates there may be a preference to provide feedback differently than immediately following a DR event for these segments. Further research could offer more clarity and direction.

5. ***The Interim Report advises that demand response potential could be greater and more cost-effective if market transformation policies and practices were adopted. What practices or policies should the Commission adopt to facilitate market transformation? How can the Commission encourage and support manufacturers producing end-uses applicable to demand response, e.g. appliances and building controls?***

When considering practices and policies to facilitate market transformation, the Commission should clearly distinguish between:

(i) Market transformation programs for the adoption of end-use technologies, for example, an appliance, process loads or other electricity consuming pieces of equipment (e.g., HVAC, electric vehicles, water pumping, etc.). These programs should be considered outside of the DR proceeding, where specific end-use adoption will serve energy policies like EE, DG, and EV unrelated to serving grid needs.

(ii) Market transformation programs for the adoption of DR enabling technologies, such as ADR, which are a set of communications, networking, telemetry, control & other systems that enable an end-use to provide DR grid service.

PG&E believes that the ADR program should be modified to strictly focus on market transformation for the adoption of DR enabling technologies – as defined in (ii) – to increase the adoption of DR enabling technologies for automation:

- The ADR program should provide incentives to encourage the adoption of the communication capability to increase the potential for DR automation, as opposed to providing incentives to encourage the adoption of the overall end-use technology.
- PG&E would also like to investigate if upstream and midstream incentive channels can further increase the penetration of DR enabling technologies. As stated in the LBNL DR Potential Study Interim Report (page 95), "The DR automation market will be transformed when control systems have communication hardware and software capabilities that can receive and send DR signals with minimal to no additional first costs."

Market transformation for the adoption of DR enabling technologies is also a key objective of PG&E's DRET Program. For instance, the DRET Program engages in standard development and working groups such as OpenADR Alliance, EPA Energy Star, CEE Connected Appliance, EPRI Connected Appliance, PNNL Connected Equipment Maturity Model (CEMM), and DOE Grid-Meets-Home Initiatives.

PG&E recommends that the Commission continue progressing market transformation for the adoption of DR enabling technologies by supporting the ADR program, DRET Program, Title 20 and 24, and standards development to increase DR enabling technology adoption and expand DR automation.

6. ***Explain and justify the most important program design changes the Commission should require for the 2018 demand response portfolio. Include a detailed explanation and justification for how this change could be made.***

PG&E is unable to provide specific program design changes as it is currently developing its next program application. However, PG&E does provide some conceptual guidelines that should be considered when designing the 2018 DR portfolio:

- DR programs should effectively and efficiently convey grid needs as they evolve. For example, future DR program design should have characteristics that reflect the location, seasons and hours when DR is most needed to serve the grid.
- DR programs should enable flexibility in how customers and aggregators can participate in DR, from being a "use limited" resource all the way to being "frequently dispatched". The Commission should therefore expect DR program design that reflects customers' and aggregators' varied opportunity costs in participating in DR while meeting the requirements to provide Resource Adequacy or other valuable services to the grid. Designing programs that facilitate customers' and aggregators' participation in a way that fits their business operations, aggregation and/or lifestyle creates a transparent load activity that is useful for the grid operators.

7. ***Over the history of the demand response programs, the Commission has approved many pilots. Pilots allow the Commission to test a new concept or program design, or advance a new policy objective or operational requirement. What current demand response pilots should the Commission consider transitioning to a program? Are there pilots outside of the demand response portfolio that the Commission should consider integrating into the demand response portfolio, either for 2018 or in the future? In addition, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison are each directed to include, with their responses to the questions in this Ruling, a list of all demand response pilots approved since 2012. The list shall include the justification for undertaking the pilot, the customer segment the pilot targets, the results of the pilot, and whether the pilot should be transitioned to a full program.***

Below is a list of all PG&E DR pilots approved since 2012:

Intermittent Renewables Management (IRM2)/Supply Side Pilot (SSP)	
Justification for the pilot	• Develop the models used by the CAISO to characterize demand-side resources. • Develop the standard and methodologies used to make the operation of demand-side resources visible to the CAISO. • Evaluate and validate the types of technology needed to allow demand-side resources to be a flexible resource to the CAISO. • Develop accurate customer load control strategies and forecast extremely short-term load consumption or reduction. • Help design current or future PG&E DR programs and form the basis to enable third parties to provide flexibility service to the CAISO. • Build on the learnings from the 2012-2014 IRM2 pilot as

	well as new information arising from the Commission and CAISO on the need for flexible resources. • Include smaller commercial and residential. • Enable participation in real-time and non-spinning ancillary services markets. • Maximize the value of DR in all possible channels to assist with multiple grid needs, to provide maximum benefit to all retail customers. • Enable the option for DR resources to be called to address local distribution reliability issues for the distribution grid. • Demonstrate the feasibility of multiple uses of Supply Side II DR Pilot resources for both CAISO markets and distribution operations.
Customer segment	Initially (IRM2), large C&I bundled, Community Choice Aggregator (CCA) and Direct Access (DA) customers with PG&E electric service. Expanded in SSP to include all customer segments bundled, CCA and DA customers within PG&E electric service.

Results of the Pilot	LBNL wrote a report summarizing the results of the 2012-2014 IRM2 pilot, which can be found at http://drrc.lbl.gov/sites/all/files/lbnl-179019_intermittent_renewable_management_pilot_phase_2.pdf
	The preliminary results for the 2015-2016 SSP, are:
	• Participants are actively bidding into wholesale day-ahead (DA) and real-time (RT) energy markets using PDR.
	    o DA market participation since April 2015.
	    o RT market participation (for non-residential customers) since August 2015.
	• Program opened to enrollment of residential customers end of 2015.
	    o No residential aggregators are bidding into the market yet.
	    o Multiple residential aggregators have gone through qualification testing but are working on recruiting more customers and/or fine-tuning their event responses to increase their load reductions.
	• Over 4100 bids and 550 awards in DA market since April 2015.
	• Participants are bidding during periods that are outside of the traditional peak periods.
	• Technologies utilized by participants include HVAC, EV, photovoltaics (PV), and battery storage.

Transition Plan	SSP program characteristics would be used to modify existing Capacity Bidding Program (CBP), which PG&E is planning to

	propose for the 2018 program cycle.
Excess Supply Pilot (XSP)	
Justification for the pilot	• Understand the extent to which demand-side management can support renewable integration. • Measure ability and willingness of different customer segments to consume or shift load when the supply of electricity exceeds demand. • Understand the best approaches to harness customer load during periods when the supply of electricity exceeds demand. • Test different approaches that improve the ability and willingness of customers to consume or shift load in response to situations when supply of electricity exceeds demand. • May include enabling technologies, financial incentives, and other drivers of customer behavior. • Inform the design of a future program, by conducting the field testing of the actions required from PG&E, customers, and third-party aggregators so that load can be increased when excess supply conditions exist. • Assessing what other triggers, other than pricing, can be used to help call events at earlier times so they can then indicate to participants to start shifting load. • Further experimentation surrounding compensation to participants. • Current standard retail electric rates may present conflicting price signals that will need to be addressed in the context of this pilot. • Factor the local distribution constraints systematically in the pilot's operations to ensure that, when situations of excess supply happen at the system level, the actions taken by participants to realign supply and demand do not create congestion on the distribution system. • Explore the appropriate baseline methodologies and evaluate if the same method leads to understanding the performance of a DR resource that is asked to shift and consume more energy.
Customer segment	All bundled, CCA and DA customers with PG&E electric service.
Results of the Pilot	PG&E opened the XSP for enrollment in late 2015 and started calling events in March 2016. PG&E will not have results from the pilot until later in 2016 but will share them with the Energy Division when they become available.
Transition Plan	PG&E recommends that for 2018 DR cycle, XSP should remain a pilot, until the current CAISO DR model enable DR resources

	to consume more. Furthermore, the XSP is still assessing and testing out various fundamental program characteristics like triggers and value that are still in flux. 2016-2017 XSP is not CAISO market integrated due to the current CAISO DR models not possessing the capability to enable DR resources that can shift or consume their load to meet excess supply situations. CAISO models like PDR and RDRR were designed to be a load reduction only model. However, the CAISO has engaged stakeholders as part of the Energy Storage and Distributed Energy Resource (ESDER) Phase 2 to construct a proposal that can enable consumption services as part of PDR. In addition, PG&E is planning to launch the Energy Matinee pilot in the Spring 2017, if the pilot is approved by CPUC.. Lessons learned from the pilot will be considered as PG&E prepares to convert XSP to a full-fledged program at some point during the 2018 DR cycle. PG&E will provide the Commission an implementation plan for the expected roll out and the details of the propose XSP program.
Transmission and Distribution Pilot (T&D Pilot)	

Justification for the pilot	• Identify the characteristics of the resources that T&D organizations need for their operations and aim to create and/or modify DR resources to fulfill these needs.
	• In the first step, the pilot will study and document the following:
	    o Time and duration of T&D operators' and planners' need for services for different types of equipment;
	    o T&D planning and operational processes to better integrate DR resources;
	    o Plans that integrate DR resources into T&D planning and operations;
	    o Impact that DR resources will have on T&D assets;
	    o Methodology to accurately forecast the capabilities of extremely locational DR resources for T&D operations;
	    o Whether DR resources can defer or postpone T&D upgrades; and
	    o Aspects and causes of constrained areas.
	• The second step of the T&D pilot will be based on the first step's findings. The second step will investigate the DR enabling technologies and resources below:
	• PG&E's current enabling and retail programs (e.g.

<table>
<tr><td></td><td>SmartAC and ADR enabled programs); and

Electric vehicles, new residential mass market DR technologies and non-DR demand-side resources, if any, that can meet the needs of T&D operations and planners.
The T&D Pilot will continue to understand how T&D operates and where DR can provide the most value in supporting local area reliability in a least-cost fashion.
In addition, explore the following areas:

Planning Tools:

Develop tools and analytics that proactively synchronize with T&D Planning.
Assemble analytics that would provide the best areas to assemble DR resources
Develop a local area DR resource valuation model to support integrated least-cost planning.

Operational Development:

Continue to improve forecasting tools, controls and communication on how DR visibility and dispatch can be better integrated with the evolving T&D operational systems and processes
Assemble cost-effective solution to monitor in real time DR resource activities.

Customer Testing:

Testing marketing approaches and incentive structures that will engage customers to provide the concentration and flexibility for DR resources to support local reliability planning and operations.

</td></tr>
<tr><td>Customer segment</td><td>All bundled, CCA and DA customers with PG&E electric service.</td></tr>
<tr><td>Results of the Pilot</td><td>
Developed offering to promote AC and pool pump kickers in Advanced Home Upgrade

Additional $400 for installation of ≥14 SEER/12 EER.
Additional $200 for installation of variable speed pool pump.

Developed 3P Mobile Home Direct Install and Proctor multi-family HVAC programs.
Prioritize targeted DSM customers in electric EE marketing campaigns.
Leveraged AC Quality Care in 2014 and leverage best practices to further target contractors in T&D regions.
</td></tr>
</table>

	• Partnering with the DRET Pilot, the T&D Pilot assess the potential of third party DR providers leveraging self-installed smart thermostats (BYOT) in the targeted substations. The primary objective of this project, as part of the greater Targeted DSM initiative, is to develop a framework wherein customer-side programs can be integrated into a least cost planning framework to support distribution system reliability.
Transition Plan	The DR T&D Pilot will, in large part, be subsumed by the combination of Distributed Resource Plans /Integrated Distributed Energy Resource (IDER) proceedings which are focused on how DERs (including demand response) can be sourced and operated for the purpose of providing local grid services. PG&E fully expects that DR will be a mainstay of DER deployments providing those localized grid services. In addition, it is PG&E's intention to use the learnings from the T&D Pilot to both inform the sourcing of new programs under Distributed Resource Plans /IDER but also to inform the enhancement of existing PG&E programs so that they can also provide additional value by providing localized grid services.
Electric Vehicle Pilot (EV Pilot)	
Justification for the pilot	• Evaluate the potential of using plug-in EVs (PEV) and/or used PEV batteries for grid services. • Determine the capacity, duration and amount of grid services that can be provided via managed charging of PEVs and/or used PEV batteries. • Evaluate the benefits and costs of utilizing managed charging of PEVs and/or used PEV batteries on the electric grid. • Evaluate the marketing and incentive mechanisms needed to obtain demand response for managed charging of PEVs and/or used PEV batteries.
Customer segment	All bundled, CCA and DA residential customers with PG&E electric service.
Results of the Pilot	Below are some preliminary findings on the EV Pilot: • PG&E and BMW enrolled 96 BMW i3 drivers. • The program is being conducted from July 2015-December 2016. • To date, 120 DR events have been called. • The BMW i ChargeForward resource delivered on both DA and RT events, modeled after CAISO requirements. • Depending which time of the day the DR event was called, 10%-75% of the capacity were delivered by the vehicle pool, with the gap filled by the stationary storage asset derived from used PEV batteries.

	• Most vehicles have participated in an event, with the majority participating in three or more. • 92% participants are very satisfied with the pilot and 88% state they would recommend the pilot to a friend or family.
Transition Plan	PG&E plans to leverage the lessons learned in this pilot to increase DR capability from Electric Vehicle Service Equipment (EVSE) in the future. While there are no plans to transition this Pilot into a program through the DR proceeding, PG&E plans to develop a charging infrastructure program as part of its EV infrastructure proceeding [A.15-02-009] which would utilize DR programs to integrate with grid operations.
Demand Response Auction Mechanism (DRAM Pilot)	
Justification for the pilot	The Commission required the IOUs to conduct the DRAM Pilot through D.14-12-024. It was developed to test: (a) the feasibility of using a competitive solicitation to procure SR DR for Resource Adequacy (RA) capacity with third party direct participation in the CAISO markets; and (b) the ability of winning bidders to integrate their DR resources directly into the CAISO market.
Customer segment	All bundled, CCA and DA customers within PG&E's electric service territory.
Results of the Pilot	• DRAM I: PG&E executed contracts with five Sellers for a total of 17.17 MW, with deliveries from June – December 2016. • DRAM II: PG&E is currently evaluating offers and will select winning offers by June 24, 2016 for January – December 2017 delivery. • DRAM III: The 2018 DRAM Working Group will commence meeting on June 21, 2016, to jointly develop a proposal for the parameters for this third pilot, with deliveries from January – December 2018. The IOUs will file an Advice Letter for the 2018 DRAM by September 1, 2016.
Transition Plan	PG&E is supportive of transitioning DRAM to a full program, but believes certain aspects of DRAM should be modified before growing its size and term (see Category 4 questions and answers for more information on PG&E's position on the DRAM).

In the 2018 DR Application, PG&E may propose other pilot(s) that will further expand the utilization of DR that can meet the needs of the grid operators and planners in order to support system, local area reliability in a least-cost fashion and meet customers and third parties future program needs.

8. ***Through the 2013-2014 demand response program year, the Utilities completed process evaluations for demand response activities on an intermittent basis. Have the process evaluations been useful and/or effective for improving evaluated programs' design and operation? Is there a need to continue the process evaluations? How often? Should there be an agreed-upon criteria for the demand response activities that should be included for evaluation? Should the process evaluations be filed formally?***

PG&E agrees that process evaluations are important and effective for improving program design, especially if the DR program cycle is extended beyond the current three years, to allow IOUs to make enhancements to their DR programs.

The criteria for process evaluations are usually developed by a third-party measurement and evaluation (M&E) vendor and jointly supported by the DR program team, DR M&E team, and the Demand Response Measurement and Evaluation Committee (DRMEC). The criteria are customized to the specific program type and the objectives of the process evaluation. Some common criteria for process evaluations include but are not limited to:

- How is the program managed at each IOU (for statewide programs)?
- What is the program reach and what are participant characteristics?
- What is the program application process?
- How have customers and vendors experienced the program?
- How do customers use the technology/platform/process?
- Is the technology/platform/process successful in providing values?
- How do customers respond to DR program events?
- Are customers meeting load shed test estimates? Why?
- How can the program change to improve the customer and vendor experience?

In the 2012-2014 DR program cycle, PG&E participated in statewide process evaluations for the ADR and SmartAC programs. Below are some of the examples of how PG&E has leveraged the process evaluation recommendations to improve program designs:

- ADR:
    - Improving DR program enrollment via marketing and outreach efforts by providing enhanced training to account representatives regarding the program;

conducting project-specific meetings with key stakeholders to provide an opportunity to better explain the program and clarify concerns.
    - Streamlining program application processes by monitoring application process timing and identifying opportunities to streamline the process.
    - Assuring quality installation of technologies by enhancing vendor quality control activities to ensure operability of technology; conducting follow-up calls with account managers and program participants at three months and six months post-installation to ensure that the technology is operational.
    - Continuing communication with participating customers by providing status updates to stakeholders and participants throughout the participation process.
    - Track effects of program design changes by tracking: (1) number of newly enrolled customers, (2) the number of participating vendors, and (3) the proportion of participants that participate in events in a given year.

- SmartAC:
    - Ensuring that QA/QC processes continue to take advantage of available smart meter data by identifying participants who use air conditioning during event hours.
    - Refining efforts to leverage smart meter data to recruit participants who are likely to provide load reduction:
        - Identify optimal customers who use air conditioning during event hours.
        - Assign customers into usage cohorts.
        - Overlay demographic and behavioral customer characteristics.
    - Testing pre-event notification which resulted in positive indicators.
    - Refining information about the program in recruitment materials, web presentment and in co-marketing with other non-DR programs.
    - Researching customer preferences for incentives and considering program redesign.
    - For 2017, proposing auto enrollment when participants move in territory and when customers move into premises with program devices.
    - Exploring new technology to facilitate real-time event feedback and more cost-effective QA/QC.
        - Testing two-way communicating load control devices for new recruits and to replace malfunctioning devices in higher AC usage customer.
        - Minimize risks of malfunction AC switch to customers during events.
        - Leverage AMI investment to provide DR.
    - Exploring 100% cycling (shed) customer participation option.
        - Tested during 2015 with minimal results.

All process evaluations are publicly posted in the CALMAC website[7/], and DRMEC is usually engaged as an advisor. PG&E plans to request process evaluations for DR programs such as Base Interruptible Program (BIP) and Capacity Bidding Program (CBP) in the next program cycle and asks the Commission to continue to allow IOUs to support this important project practice.

C. Category 3 Questions: Increasing Participation and Performance in Demand Response

1. *The Interim Report has suggested at least six strategies that could increase participation in demand response, including lowering the cost of demand response, target marketing, market transformation of technologies, and aligning profit mechanisms across end-users, aggregators and utilities. What policies should the Commission adopt to increase participation in demand response?*

PG&E is generally supportive of the strategies discussed in the Interim Report. PG&E has provided comments on some of them throughout its response to the ALJ Ruling and comments below.

Beyond Widgets: PG&E addresses this issue in its response to Question 2 in Category 2.

Open Standards: The Interim Report recommends that "[a]dditional outreach should be done to inform customers regarding the enhanced value to them for making sure any investment on their part adheres to the most relevant standard." (Interim Report, p.94) PG&E agrees with this statement and recommends that this outreach also be conducted at the California Energy Commission (CEC) with other Title 24 stakeholders. The Commission could encourage the CEC to modify Title 24 Building Codes to not only require controls to be capable of accepting an OpenADR signal, but also to specify that the signal be OpenADR compliant, and the lighting and HVAC controls be OpenADR certified. Open standards also help to transform the market and increase adoption of DR Enabling Technologies, which was addressed in Question 5 in Category 2.

7/ www.calmac.org.

Building Codes: PG&E agrees that current codes encourage the adoption of DR Enabling Technology, but the codes do not specify any type of controls for time-of-use (TOU) or time varying prices. The Commission could encourage the CEC to refine the building code language to include time varying rate controls capability, in addition to the DR requirements, and also change the building code to specify DR controls be OpenADR certified. Current building code requirements do not actually require commissioning the controls so that they can be utilized for DR. The Commission should encourage the CEC and other Title 24 stakeholders to develop a process to educate and encourage activation and testing of controls that enable time varying rates and for DR events.

As PG&E stated in its response to Question 3 in Category 2, there also is confusion among building code officials and market actors regarding Title 24 requirements for DR automated technology. PG&E recommends that the Commission work with CEC and other Title 24 stakeholders to further evaluate knowledge gaps for the Title 24 requirement, while leveraging the findings of the PG&E DRET assessment.

DR, Load Shape Comparisons and Peak Demand Benchmarking: PG&E addresses this issue in its response to Question 5 below. In its response to Question 4 in Category 2, PG&E also explains the feedback it provides to DR customers after events.

2. *What policies should the Commission adopt to influence behavior change in response to time-of-use pricing?*

PG&E recommends that the Commission address TOU rate issues outside of the DR proceeding. In PG&E's view, time variant pricing, including TOU rates, is one approach to influencing behavior change. Different prices in effect throughout the day provide a signal to customers that convey the cost of providing energy when demand is higher or lower. Higher on-peak rates provide customers an incentive to reduce their consumption or shift usage to lower cost off-peak periods. Technology and tools could also be instrumental in influencing behavior change. The IOUs are conducting residential TOU pilots that will evaluate the effect of technology and tools on behavior change.[8/] PG&E's DR team will take into account any findings from the residential TOU pilots, which might be applicable in the context of DR program design.

3. *What design changes could the Commission make to current demand response programs to specifically increase the number of customers participating in the programs?*

PG&E is unable to provide specific program design changes as it is currently developing its next program application. To further enrollment growth in DR programs, PG&E plans to support the development of a vibrant and innovative DR market. Complementary to the non-IOU DR programs that will materialize from both Rule 24 DRAM and non-DRAM procurement channels, IOU-operated DR programs will be an additional venue for market participants who are unable to economically build access to CAISO markets, as well as a vehicle to expand access to DR programs to new or under-served segments of the market. This will result in a more favorable environment for a wide range of third parties and aggregators to enter the DR market, with multiple choices for customers to participate in DR.

PG&E is also considering an additional design option for PG&E-operated DR that would offer customers and aggregators the ability to elect their own availability to provide value to the grid, in a manner that reflects customers' varied opportunity costs. Such a program option would attract new DR customers by considering each customer's unique ability to respond to an event. PG&E will also include more programs open to residential customers.

PG&E will also be exploring opportunities to make enrolling in its DR programs and the DRAM easier and less time intensive. Pursuant to D.16-06-008, this will include implementing a "click-through" process that can be used by third-party DR providers for customer consent to release of their data to third parties.

8/ PG&E's TOU pilots were adopted in Resolution E-4762, pursuant to D.15-07-001.

4. ***Should the Commission allow, prohibit, or require the use of technology deployment within the demand response auction mechanism? What policies would be required?***

The Commission should allow, but not require or prohibit the use of end-use or DR enabling technologies for the DRAM, nor should DR programs promote the adoption of specific end-use technologies. Customers participating in the DRAM are able to adopt end-use technologies to use in the DRAM through the IOUs' EE, DG, and EV programs. To the extent the Commission wants to drive the adoption of specific end-use technologies, this should be done through these other programs, with the ADR program potentially providing incentives for automation.

5. ***The Interim Report observes that large commercial building owners know the energy use intensity of their buildings. Underscoring that data on peak demand load shapes is less available, the Interim Report suggests that this data could communicate an understanding of energy usage beyond kilowatt hours thus leading to a better awareness of demand response.9 Do you think that a customer attaining their peak energy use data is important to the success of demand response in California? What steps could the Commission take to foster the availability and use of this data?***

PG&E agrees that, as a general principle, customers who are aware of when they consume the most energy are likely to be more successful in lowering their energy bills because they know at what time of day they should be targeting their efforts. PG&E is very supportive of customers having access to their energy usage data in a useable format. In some instances, a customer's peak load may not coincide with DR needs to support the hours of highest value to the grid. If that is the case, the customer will have limited success in providing DR despite this knowledge. For example, if the customer's peak load occurs outside of the summer Resource Adequacy (RA) Availability Assessment hours (1:00 p.m. – 6:00 p.m.), then the RA value of the customer will be less than the amount of load it can drop when its load is peaking. It is not necessarily the case that a customer's peak load must coincide with the system or local peak to provide valuable DR, but a coinciding peak does often maximize the amount of the customer's load that is available for load reduction when it is likely to be most needed.

All of PG&E's customers currently have access to their load data to varying degrees. PG&E provides an overview of this data availability:

1. **Share My Data** (formerly Green Button Connect My Data): This is a web-based platform that allows customers and third-parties to obtain 24/7 continuous access to energy usage data for any purpose authorized by the customer. Customers provide online authorization for PG&E to release their interval gas and electric usage data to a registered third party on an ongoing basis.

2. **Green Button Download My Data:** This tool allows residential and SMB customers to download their electric and gas interval usage data, interval cost data, and billing data one Service Agreement at a time. These data can be downloaded and sent to third parties.

3. **Download My Data:** This tool allows non-residential customers to download all of their electric Service Agreements in a single, centralized location. They can download up to three years of historical data and daily usage files.

4. **InterAct System:** InterAct is similar to Green Button Download My Data in the energy usage data it provides for large C&I customers. The tool also provides advanced DR analytics.

5. **Stream My Data** (also known as Home and Business Area Network)**:** This platform is a way to help residential and SMB customers save energy and money by providing real-time electricity data through an energy monitoring device. This device helps customers understand how and when they are using electricity, as well as the related costs.

6. **Energy Data Request Program:** Online data request form by which government agencies and research institutions can submit requests. The data is generally aggregated or anonymized. However, qualifying research institutions may obtain data with personally identifiable information.

D. Category 4 Questions: DRAM

1. ***If the Commission determines it reasonable to continue the demand response auction mechanism beyond the pilot phase, funding will be necessary. In order to fund such an auction, the Commission must first determine the size of a DRAM program. Explain and justify basis on which the Commission should design the size of the DRAM program. Should the DRAM program size be based on an overall budget limitation, a megawatt limitation, the number of available registrations in the CAISO market or another metric? Additionally, explain and justify the length of delivery contracts for a DRAM program.***

PG&E is supportive of continuing DRAM-like auctions as a mechanism for future DR procurement, but believes that changes to certain programmatic elements of this pilot need to be considered before it is transitioned into a permanent program of any appreciable size (beyond 10 MW) or length. Foremost, the program size and term of an RA auction should be reflective of the needs of each IOU. PG&E provides the following additional considerations that should be factored into future program design and scale for the DRAM.

a. Modify the DRAM Contract to Increase the Reliability of DRAM Resources

The future DRAM program must provide IOU Buyers more certainty around their physical delivery of contracted RA capacity, through stronger DRAM Purchase Agreement (PA) provisions. In the 2017 DRAM RFO Pro Forma Purchase Agreement, if Sellers are unable to register their resource due to actions or inactions of Buyer or the CAISO, they may either adjust their monthly quantity or outright terminate the agreement under Section 1.5(b), with only a showing of commercially reasonable efforts and exemption from the contract's early termination penalties. This ability to reduce deliveries or terminate the agreement at a DRAM Seller's election severely undermines the ability of PG&E to conduct forward planning based on a reliable resource.

Further, although the contracted monthly quantity of RA capacity is set forth for each applicable Showing Month during the term of the PA, under Section 1.6, Sellers are able to elect monthly payment based on either capacity tests, bids into the CAISO market, or dispatches of DRAM resources, at their sole discretion. By not linking payment to actual dispatch of DRAM resources, performance of actual DRAM resource by the DRAM Seller is not incented – the Seller is paid regardless of delivery at the Seller's election. While the Seller is obligated to indemnify Buyer for costs arising from the Seller's failure to provide monthly quantity promised under a supply plan, under the final paragraph of Section 3.5 of the PA, the Seller is also absolved of the consequences of its delivery shortfalls with regard to CAISO costs related to Shortfall Capacity allocated by CAISO to Buyer. Together, this flexibility around actual deliveries and limited consequences for failure to deliver quantities set forth in the agreement make RA capacity from the DRAM PA unreliable.

Future DRAM auctions should be structured to procure firm RA capacity. If the DRAM Sellers do not deliver according to contract, there should be damages consistent with other RA contracts. If failure to deliver persists, there should be termination rights and damages for the IOUs.

The DRAM contract may also need to change due to the changing environment and requirements at the CAISO regarding multiple use applications (MUA) for energy storage. For example, the UDC and LSE may need more information about the CAISO registrations and the DRAM Seller's use of the customers participating in various MUA alternatives, in order to perform their responsibilities.

b. A Bid Cap Should be Used to Ensure the Cost-Effectiveness of Bid Prices

Bids stemming from the 2016 and 2017 DRAM solicitations have generally been in line with IOU DR program capacity costs. However, the IOUs should not be required to accept bids at any price.[9/] In order to ensure that the ratepayers are provided with the best DR value possible, the IOUs will need some latitude to reject bids that are unreasonably priced.

9/ The IOUs do currently have the ability to request Energy Division exclusion of any DRAM bids it deems unreasonable. This discretion should be provided to the IOUs without approval by the Energy Division.

This discretion may be provided in a form of a maximum bid price and as a deviation outside of a standard distribution. Another simple way a soft price cap might be determined is to develop a reasonable pre-determined capacity cost that bids cannot exceed.[10/] The number could be used for both IOU and third party supply-side programs.

c. Availability of Rule 24 Registrations Continues to Be a Factor in the DRAM Program Size

The size of both the 2016 and 2017 DRAM pilots have been constrained by available Rule 24 registrations. The number of registrations will potentially continue to be a limiting factor for future program size until either i) the CAISO DR market reaches some yet unknown "steady state" participation volume, or ii) full Rule 24 implementation is approved and put into place.

PG&E understands that the Commission has indicated that registration volume should not be a barrier to Rule 24 participation and has done its best to balance its ability to accommodate Direct Participation volumes consistent with market interest, cost and pilot parameters. Currently, Rule 24, and hence DRAM, is limited to 40,000 registrations upon completion of its Intermediate Implementation step in the first quarter of 2017. Expansion in Rule 24 participation volumes beyond this amount will subsequently be permitted through a Tier 3 Advice Letter, a DR program cycle application, and/or a separate Rule 24 full implementation application.[11/] The relatively few and scattered number of opportunities to recover costs for Rule 24 expansion along with any associated approval and "build" timeframes could continue to put additional pressure on meeting growing market registration volumes during the initial years of Rule 24 implementation.

10/ For example, next year's successor to the CAISO CPM, which will be called the Competitive Solicitation Process, could be used as a benchmark.

11/ D.16-03-008, Ordering Paragraphs 12 and 13.

d. DRAM Program Terms Should be Increased in Length and Staggered

PG&E is supportive of increasing the DRAM term up to five years in duration, as long as the DRAM contract is modified as described in the Category 4 Questions: DRAM, discussion herein. A term longer than one year would make the Rule 24 recruitment and other start-up investments more worthwhile for the DR providers, and presumably result in more competitive prices due to economies of scale. The contract term should not go beyond five years at this time for several reasons: (a) the initial investments may not be large enough to warrant a longer contract term; (b) DR capacity costs could change significantly within five years, making the contracts either too costly or unsustainably cheap; (c) IOU capacity portfolio needs may change significantly within a period of more than five years; and (d) the DRAM pilot is still in its early stages, there is still a lot to learn about how it will fit into PG&E's portfolio, and the best contract provisions for the Buyer and Seller, before making longer-term commitments.

Additionally, PG&E proposes that DRAM capacity solicitations be staggered across multiple years. For instance, certain products could be offered in one-, three- or five-year terms to allow for risk mitigation for both the Buyers and the Sellers.

2. ***Provide an estimation of a budget for each of the three demand response utilities to administer a DRAM program based on your responses to question number 1 above.***

PG&E does not provide a specific megawatt amount for a DRAM program size when answering Question 1 above, because of its position that program size should be based on the considerations described in our Question 1 response. However, on March 18, 2106, in its Response to ORA Data Request 005-Q02, in Application 14-06-001, PG&E estimated that it can possibly manually manage up to 75,000 registrations prior to converting its Rule 24 processes to mass market implementation. PG&E bases this budget estimate on this assumption and also assumes the following:

- 90% of PG&E's 75,000 registrations will be used by DRAM participants (67,500); the other 10% of the registrations (7,500) will be used by non-DRAM participants for other supply side products.
- Of the 67,500 DRAM registrations, 90% (60,750) are applied to residential Proxy Demand Resources (PDR). The remaining 10% (6,750) are applied to non-residential Proxy Demand Resource (PDR).
- In PG&E's service area, residential customers generally provide around 0.5 kW per customer, meaning 30.375MW could be provided by 60,750 residential PDRs.
- A 50/50 MW split between the make-up of residential and non-residential DRAM resources.

The total size of the DRAM program in this scenario is two times 30.375MW (for the residential and non-residential DRAM resources), or 60.75 MW. Based on this 60.75 MW, PG&E estimates capacity costs of approximately $4.8 million (based on a capacity payment of $80/kW-year) with a program administration cost of approximately $1.3 million.

The costs shown above are representative of one of many DRAM scenarios that vary by customer composition, registration volume and capacity costs. As a general matter, PG&E would expect annual DRAM program costs to range between $5 and $10 million.

On February 8, 2016, in Supplemental Advice Letter 4719-E-A, PG&E provided budget estimates for its 2017 DRAM pilot. Care should be taken in comparing the program administration costs between the DRAM pilot and an ongoing program. Many program development and administrative costs required for the DRAM pilot are not charged directly to the DRAM budget, but would be once DRAM becomes a permanent part of PG&E's DR portfolio.

3. ***Provide a detailed list of metrics, data and issues that the Commission should consider before transitioning from a DRAM pilot to program.***

The following metrics, data, and issues should be considered in transitioning DRAM from a pilot to a program.

Metrics and Data for Consideration: Article 3.3 of the DRAM PA requires that the Seller "provide to the CPUC all information requested by the Commission relating to Seller's obligations and performance pursuant to this Agreement." The Energy Division should require that the Sellers provide it with the following information:

- DRAM Seller bid prices and dispatch history by day, month and amount, and an illustration of bid accuracy during dispatch days including DR exception dispatches (when they get an award but did not dispatch).
- All CAISO testing results of resources.
- Number of customer accounts registered in the Seller's DRAM resources at CAISO, but not used in the resources by month.

The Energy Division should use this information to inform itself whether or not the DRAM Sellers are providing the appropriate benefit to the grid, and whether they are delivering the contracted capacity according to their "Notice of Demonstrated Capacity." These data will additionally help determine whether using the contract capacity as the qualifying capacity (QC), and not the DR Load Impact Protocols, is a reliable method for future QC determination in DRAM beyond 2019.

These data can also provide insights into how efficiently PDRs and Reliability Demand Response Resources (RDRRs) are working in the CAISO market. For instance, whether most of the registrations are being used in Seller resources or are they not being used for direct participation for whatever reason? The IOUs should also be allowed to require anonymized customer data from the Sellers through their DRAM Agreements to ensure that they are getting the appropriate RA value established in the Agreements. Moreover, information about the Sellers' performance under the pilot contracts is necessary for the IOUs to identify how to improve the DRAM as a vehicle for obtaining reliable services to support the grid and provide capacity. The IOUs must have access to this information for lessons that can be learned.

Issues for Consideration:

- The DRAM contract should have stronger performance guarantees than the current contract provides. Please see the response, pages 29 to 30 above.

- Qualitative factors should be considered in future DRAM bid selection, such as bidders' experience in DRAM/Rule 24 or other PG&E programs, counterparty concentration, and project viability. PG&E should be allowed the discretion to make the best decisions on how ratepayer dollars are most effectively spent.
- The residential set-aside requirement should be removed. So far, the residential bids are competitive with the non-residential bids, and though this has not proven to be a difficult requirement to meet thus far, PG&E would like discretion in choosing the most economical bids for its portfolio needs, regardless of whether the bids are residential or non-residential.
- Scheduling coordinator costs are currently paid by IOUs. These costs should be incorporated into bid price and paid by the Seller in the future.

E. <u>Category 5 Questions: CAISO Market Integration of Utility Programs</u>

1. *Should the Commission require that all demand response resources have one trigger or should the Commission allow multiple triggers, as is the current policy?*

The Commission should continue to allow IOU DR programs to have multiple triggers. The objectives for IOU-operated DR programs are typically multi-faceted to properly support multiple grid needs, including capacity, energy, T&D, and reliability. To deliver on these objectives, flexibility in the way programs are operated and dispatched is instrumental. To preserve this flexibility, the Commission should continue to allow such IOU-operated DR programs to have multiple triggers with the discretion in how IOUs apply them.

Multiple triggers provide the IOU with needed flexibility in how it can dispatch the program because a given trigger may not always capture the need of the grid on a given day, or on a given hour. It is PG&E's preference to avoid situations in which its DR resources are critically needed but cannot be dispatched because the appropriate trigger is not contained in the program tariff. For example, the Capacity Bidding Program (CBP) has a set of multiple triggers that give PG&E the flexibility to dispatch resources under many circumstances:[12/]

1. 15,000 Btu/kWh heat rate
2. CAISO schedules the CBP as a Proxy Demand Resource (PDR)

12/ http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-CBP.pdf, Sheet 11.

3. When PG&E determines that generation or transmission and distribution capacity is inadequate
4. The forecasted temperature within a subLAP exceeds the pre-determined temperature threshold for that subLAP

With these triggers in place, PG&E is able to dispatch CBP when:

- CAISO energy prices are high (Trigger 1)[13/];
- When energy prices do not reflect stressed system conditions, the temperature trigger can be used for reliability (Trigger 4); and
- If there is a forecasted or existing reliability problem impacting the transmission or distribution system when energy prices and temperatures are low, the CBP can be dispatched using Trigger 3.

Similarly, PG&E's Base Interruptible Program (BIP) has multiple triggers which specify conditions under which the CAISO can request it be dispatched, or PG&E can decide to use it without CAISO requesting it.

Even when a program trigger is met, the IOUs should continue to be allowed to have discretion in dispatching their DR programs. Multiple additional decision factors – for instance the number of dispatches to date (which impacts customer fatigue), how far into the summer the event occurs, number of dispatch hours remaining in the month, availability of other lower cost resources, etc. – then need to be accounted for, to ensure that DR is being used when it is most valuable to the grid.

2. *In designing triggers for demand response programs, what elements should the Commission take into account? To what extent does participant fatigue factor into trigger design? Explain in detail what steps the Commission should take to ensure that demand response programs are being maximized (bid at prices that result in dispatch) while avoiding participant fatigue.*

PG&E recognizes that it has been a challenge to sustain the amount of DR that is enrolled and ensure its availability due to customer fatigue. Based on anecdotal feedback from DR customers and aggregators, PG&E believes that customer fatigue may have been a contributing factor in some of its AMP aggregators ending their contracts, and CBP megawatts dropping significantly. To better manage customer fatigue, customers should

13/ D.16-06-029, Ordering Paragraph 29 directed the IOUs to develop a methodology to determine a price trigger for the CBP, so this trigger is subject to augmentation or revision.

have greater flexibility in how they can participate in PG&E-operated DR programs, with two main options:

1. Offer the option for customers and aggregators to elect their own availability to provide value to the grid. By design, this type of participation option would be at customers' discretion and would therefore be less likely to result in customer fatigue. PG&E believes that this participation option should also be attractive to customers capable of more frequent dispatch, either due to the nature of the load they shed during a DR event (e.g. lighting), or the end-use technologies they automate to reduce load (e.g. batteries), with little or no disruption to their lifestyle, comfort or business operations. This participation option will also accommodate customers who are unable to meet the minimum requirements for an RA resource on their own, thus making DR participation a more feasible option.

2. For PG&E-operated DR programs for which the decision to be dispatched is not at customers' discretion, the Commission should not seek to maximize the number of dispatched hours of DR regardless of the conditions. Instead, and similar to other generation resources, the goal should be that the most economic resources are dispatched. This is the focus of the annual Energy Resource Recovery Account (ERRA) proceeding and reflects the prudent use of ratepayer funds. Applying this to DR programs, the cost of DR program dispatch is reflected in its opportunity cost which in turn reflects the willingness and capability of customers to respond to an event.

3. ***There has been discussion regarding the ability to predispatch demand response resources in the day-ahead market to mitigate local contingency on the grid. What is the definition of pre-dispatch?***

The term "pre-dispatch" in the context of DR providing local reliability is more accurately characterized as "pre-contingency dispatch". This refers to the scheduling by the CAISO of a long-start resource so that it is available should there be a major contingency under 1-in-10 conditions.[14/] For long-start generators, this typically results in the generator being scheduled in the day-ahead market, sometimes out of merit, to the minimum power (Pmin) level. This leaves the generator available to be re-dispatched upward should there be

14/ These conditions serve as the basis of the CAISO's Local Capacity Technical Study.

a major contingency. It is not clear how "pre-contingency dispatch" would be defined or implemented for DR resources.

PG&E believes that this issue should be addressed in the RA proceeding, as it is currently scoped. Decision 16-06-065 in R.14-10-010 proposes to convene a working group following completion of a CAISO stakeholder process to determine how "slow start" DR can provide local reliability. It is in this venue where the definition of "pre-contingency dispatch" should be discussed so that it can be done in the proper context. With this caveat, PG&E provides elements of responses to Questions 4 and 5.

4. *What is the impact of pre-dispatching demand response resources if they are not ultimately needed in real time and not dispatched?*

Implementing a "pre-contingency dispatch" of DR resources and calling off the DR resource near real time will impact the CAISO's real time market and operations. Currently, if a DR resource is awarded and dispatched in the CAISO's day-ahead market and ultimately is not needed, the CAISO will optimize in real time the balance of supply and demand. If the CAISO were to adopt a definition of "pre-contingency dispatch" that would entail a DR resource being somehow "called off" prior to dispatch, this would require changes to the CAISO's systems and tariff. The impact on the CAISO is unclear. The impact of this practice on customers is also unclear. If the frequency of "pre-contingency dispatches" is high, it could have an impact on customer fatigue. Another factor that will drive customer impacts is how much time in advance of real-time the dispatches are called off.

5. *Explain and justify whether customers should be compensated for being pre-dispatched even if they are not ultimately dispatched?*

Customers may need to be compensated for being "pre-contingency dispatched", depending on how this is defined, even if they are not ultimately dispatched, because the customer may be incurring an opportunity cost for each instance it makes itself available. The availability provides an option value to the CAISO to dispatch the resource if needed, so it might be appropriate for customers that are called off to receive either a standardized payment or a payment that is in some way related to the wholesale energy price. Because this issue is related to the energy market, it should be first addressed in a CAISO stakeholder process.

6. *What are the practical implications of different baselines between utility demand response programs and the baselines in the CAISO tariff?*

Currently, there are three differing methodologies to evaluate what a DR resource actually delivered:

1. Retail IOU DR program baselines to evaluate capacity and energy performances, that are based on Commission-approved methodologies;
2. Wholesale CAISO baseline to evaluate energy performance, based on CAISO approved methodologies and tariffs; and
3. The DR Load Impact Protocols used to determine the actual performance of an IOU DR program and obtain the forecasted capacity value for IOU-operated DR programs. The DR Load Impact Protocols determine the actual performance and updated forecasted capacity value after the DR operating season concludes, and is recognized in the RA and Long-Term Procurement Plan proceedings.

Inconsistencies between these three differing methodologies can affect incentive and penalty payments because they can generate inconsistent results, and raise questions as to what a DR resource actually delivered. DR providers and customers would be financially impacted by this inconsistency. Furthermore, the CAISO's methodology for measuring a DR resource's performance in the wholesale market could result in penalties or rewards through the CAISO's RA Availability Incentive Mechanism (RAAIM). The RAAIM is a mechanism to ensure that resources bid consistently and in accordance with their CAISO supply plan. If the capacity value of a DR resource, as determined by the Commission-approved baseline methodology, differs from the capacity that is delivered into the CAISO as measured by the CAISO's baseline methodology, the IOU and non-IOU DR providers risk a RAAIM penalty, even if the DR resource delivers the correct amount of capacity as defined by the Commission.

7. *Explain and justify whether and how the Commission should revise current utility demand response program baselines? Address the question of when the Commission should commence such a revision given that the CAISO is currently examining the addition of baselines to its tariff in Phase 2 of the Energy Storage and Distributed Energy Resources (ESDER) initiative.*

For the reasons discussed in PG&E's response to Question 6 above, the Commission should evaluate and modify retail baselines that affect the energy performance calculation of DR resources in order to be consistent with the work the CAISO has done around expanding the use of Type 1 and Type 2[15/] baselines, as well as the work currently undertaken as part of the Energy Storage and Distributed Energy Resources (ESDER) Phase 2 stakeholder initiative.

It is important that the energy performance baselines be aligned with the baseline methodologies used to determine the capacity values of DR. The Commission has jurisdiction over the capacity valuation of DR programs. In D.16-06-045 in the RA proceeding, the Commission committed to reviewing the role of the DR Load Impact Protocols in setting the RA value of DR programs. The Commission should commence review of this issue once the CAISO's new baselines are approved by the FERC.

8. *The CAISO recently established a methodology for statistical sampling for settlement purposes. What, if any, additional Commission policies are needed to facilitate the market integration of multiple, aggregated small customer loads?*

PG&E notes that statistical sampling for settlement purposes is a method for informing a baseline calculation and is not a baseline methodology in and of itself. PG&E commends the CAISO's approval of a methodology for statistical sampling for settlement purposes, as part of its CAISO ESDER Phase 1 stakeholder initiative. This methodology will facilitate the market integration of multiple, aggregated small customer loads.

15/ http://www.caiso.com/Documents/Section10_Metering_asof_Jun3_2016.pdf - CAISO Metering section 10.1.7

PG&E is working on potential technical enhancements to the current statistical sampling methodology, working with the Stanford Linear Accelerator Center to determine a more efficient sample by leveraging their clustering tool and research. PG&E will be sharing the progress and findings from this technical assessment with the CAISO and any other interested stakeholder.

9. ***Explain and justify whether and how the Commission should standardize the penalties for non-performance across the utility demand response tariffs and demand response contracts with third-party providers? Explain and justify whether CAISO market penalties should be incorporated into this standardization?***

As a matter of principle, there should be a level playing field in how penalties are applied to similar DR programs with comparable requirements. Though PG&E supports the principle that similar DR programs should have similar penalty structures, PG&E notes that proper recognition of what "similar" means has not yet been defined. PG&E contends that none of its DR programs, including the DRAM, are "similar" and therefore should not have standardized penalties. CAISO market penalties should not be incorporated into any effort to standardize penalties because the CAISO penalties are already being imposed upon the DR provider as part of the existing market rules.

The Commission should consider that each DR program has its own balance of risks and rewards which is unique to each program. The Commission addressed this to a limited extent in D.16-06-029 when it found that the CBP was justified in having a different penalty structure from the DRAM because the CBP has more risks.[16/] Having a portfolio of DR programs with different risk/reward balances is necessary so that customers can decide which risk/reward profile best suits their capabilities. The penalty structure of a DR program should reflect several factors such as payment level, degree of predictability required of the program (enforced through a penalty mechanism), availability of the program, and speed of dispatch. As an example, the Base Interruptible Program (BIP) pays a comparatively high

16/ Decision 16-06-097, p.62; Finding of Fact 97.

capacity payment but it is highly predictable in its performance (the Firm Service Level is determined annually), is available 24 hours day, seven days a week, year-round, and responds within 30 minutes of being notified by the IOU. It therefore has, and should continue to have, a penalty structure that is much more rigorous than the CBP, which receives a lower payment than BIP, allows for monthly adjustments to nominated MWs, and has other more flexible terms. PG&E believes these differences are appropriate.

10. ***Currently, capacity incentives are competitively established (via competitive bids) for third-party providers participating in the CAISO market, administratively established for utility programs, and competitively established (via requests for offers) for third-party contracts with the utilities. Explain and justify whether the Commission should align the capacity incentives for demand response resources provided by utility programs with those provided by third parties? What are the advantages and disadvantages of moving to a competitive framework for all capacity incentives?***

For similar reasons explained in PG&E's response to Question 9 on the standardization of non-performance penalties, it would be inappropriate to align capacity incentives among all IOU and third-party DR programs. Each DR program requires different degrees of predictability, response capabilities, and flexibility in use. Furthermore, if the Commission aligns capacity payments among all DR programs, it would defeat the purpose of having different DR programs because DR customers would simply enroll in the program with the least rigorous operational requirements and penalty structure. Finally, aligning capacity payments with the results of competitive procurement is not certain to result in incentive payments that are considered cost effective according to the DR Cost Effectiveness Protocols because competitive procurement is not guaranteed to result in a cost-effective price.

PG&E sees no advantages to moving to a competitive framework for all capacity incentives. Disadvantages of moving to a competitive framework for all capacity incentives are that 1) it would prevent the IOUs from designing programs that provide a unique balance of payment level, degree of predictability required of the program, availability of the program, speed of dispatch and frequency of enrollments; 2) it could open the door to potential gaming by DR providers if the DR market is not sufficiently liquid, and 3) it may reduce the certainty of a specific level of capacity payments to DR providers.

11. ***The Supply Resource Demand Response Integration Working Group Report highlighted the relationship of the net benefits test and the default load adjustment. Explain and justify whether the Commission should reevaluate its rules established in D.12-11-025 regarding the net benefits test and the default load adjustment?***

PG&E would support the elimination of the Commission's prohibition against DR providers bidding bundled service customer load into the CAISO market below the Net Benefits Test (NBT) threshold price. In Ordering Paragraph 1 of D.12-11-025, the Commission prohibited this practice so as to avoid the Default Load Adjustment (DLA). Since then, it has been clarified that the CAISO does not apply the DLA in the Day-Ahead Market (DAM) and is only used with the Real-Time Market (RTM) price. So, even if the DR provider bids into the DAM above the NBT threshold price, if the RTM price clears below the NBT threshold price, the DLA is applied. This appears to defeat the purpose of the Commission's prohibition in OP 1 of D.12-11-025, so PG&E recommends that the Commission reconsider this matter. Though this issue must be addressed in a CAISO stakeholder process, PG&E would also now support the removal of the DLA which is subject to FERC jurisdiction.

12. ***Following the integration of utility demand response programs into the CAISO market, explain and justify whether the Commission should require the utilities to continue to file the weekly demand response exception report required by D.14-05-025 and Resolution E-4708.***

Beginning in May 2017 for any programs integrated as RDRR and in 2018 for programs integrated as PDR, the weekly DR exception reports should be discontinued. The DR exception reports also should not be expanded to apply to the IOUs' critical peak pricing programs which are not integrated into the CAISO market.

ORA has opined that programs fully integrated into the CAISO market should not be subject to DR exception reporting. In its "Workshop Report on the April 24, 2015

Demand Response Exception Reports Workshop", ORA stated, "that in terms of Supply DR, if the entire program is bid into the CAISO market, it would not need to be included in the report. But if only a portion of it is bid into the CAISO market, it would still need to be included in the report." (Workshop Report, p.20-21) Given ORA's stated position and the recent Commission decision in the DR rulemaking that an entire DR program must be integrated into the CAISO market to receive RA credit, integrated IOU DR programs should not be included in DR exception reports.[17/] Therefore, because all dispatchable IOU DR programs other than critical peak pricing (Peak Day Pricing and SmartRate) must be integrated into the CAISO market no later than January 2018, the DR exception reports should be discontinued. These programs will be wholesale resources and subject to review in other proceedings, such as the ERRA proceeding, so it would be redundant to require the IOUs to continue submitting DR exception reports.

Respectfully Submitted,

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17/ Decision 16-06-029, Ordering Paragraph 17.